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Effects of Vertical Heterogeneity on Waterflood Performance in Stratified Reservoirs: A Case Study in Bangko Field, Indonesia

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Abstract

Stratified reservoirs may have different types of heterogeneity in terms of grain size distribution in vertical direction. Geological surveys (*i.e.* using well logs) have long recognized the existence of fining upward and coarsening upward formations. In this study, such formations refer to as systems with decreasing upward and increasing upward permeability trends, respectively. Many waterflood candidate reservoirs have been found to follow either classification. However, the awareness of including this distribution classification as one of the screening criteria prior to waterflooding has not been established in the oil industry.

A simulation study using a number of conceptual stratified reservoir models has been conducted. The results show that grain size distribution classification should have significant impact on waterflood performance. Each of the two classifications yields different effects on vertical sweep efficiency resulting from different crossflow mechanisms, which consequently gives different waterflood performance. It has been found that the oil recovery from waterflooding a reservoir with coarsening upward formation will always be higher than that from waterflooding exactly the same reservoir but with the opposite classification (*i.e.* fining upward formation) even though the two reservoirs are of the same level of heterogeneity (*i.e.* similar values of coefficient of permeability variation). In this study, the degree of heterogeneity effects on recovery were investigated as well as the magnitude of vertical-to-horizontal permeability ratio effects. Also, permeability noise was addressed as the reservoir may contain contrast permeability streaks in between the adjacent layers.

A correlation has been derived based on the simulation results and has been proven to be able to predict simulation results with relatively good accuracy. Validations performed by comparison to actual production from a simple injection scheme (one injector and one producer) in Bangko Field, Indonesia, indicate that oil production rates obtained from the correlation show good agreement with those of production history.

Introduction

Heterogeneity plays an important role in predicting waterflood performance of a stratified reservoir. Heterogeneity may take place in both horizontal and vertical directions. In this study, we will consider the problem of vertical heterogeneity. One aspect of vertical heterogeneity is permeability variation. This situation may result from various geologic processes that took place during the sedimentation of the reservoir.[1] The sedimentation of a certain reservoir rock may vary and take place at different geological time from that of another leading to a somehow unique classification of grain size distribution for the corresponding reservoir. This is the reason why a certain formation may exhibit a fining upward or coarsening upward grain size distribution classification. This phenomenon may be observed from the gamma ray log results of the reservoir, which is usually reported as the stratigraphic property of the reservoir. A fining upward grain size distribution indicates that the grain size of the rock becomes finer in an upward sequence, which consequently results in a decreasing upward trend of the permeability values. A coarsening upward grain size distribution, on the other hand, indicates a situation in which the grain size of the rock becomes coarser along the upward direction thus, an increasing upward permeability trend is observed. This will lead the formation to becoming a uniquely stratified reservoir.

The effects of such types of heterogeneity on waterflood performance in reservoirs are investigated in the present study as well as the effect of the level of permeability variation. The effect of varied magnitude of crossflow is also studied by varying the value of vertical-to-horizontal permeability ratio (k_v/k_h). A simulation approach is applied in this study by using a numerical three-dimensional streamline simulator.

From the above description, the following objectives are derived:

1. To observe and determine the effects of the two classification of grain size distribution on waterflood performance in stratified reservoirs.
2. To observe and determine the effects of varied level of

permeability variation on waterflood performance in stratified reservoirs.

3. To observe and determine the effects of varied magnitude of crossflow on waterflood performance in stratified reservoirs.

Several assumptions are subject to this study as stated below:

1. All the models are conceptual with reservoir being strongly water-wet.
2. The injection of water starts as the reservoir is put on production, therefore no history matching is necessary.
3. The waterflooding system consists of one injector and one producer.
4. The wells are perforated along the interval of the productive zone.
5. Each layer is equal in thickness with one another.
6. Mobility ratio between the displacing and displaced fluids is less than unity ($M < 1$).

Waterflooding Stratified Reservoirs

Normally, the methods for predicting waterflood performance in stratified reservoirs are classified into two different types. The first type is for a reservoir consisting of non-communicating layers in which no vertical flow or crossflow occurs between layers. In this case, it is assumed that each layer is separated by a continuous impermeable shale barrier from another. Dykstra and Parsons[2] provided a very basic calculation method for predicting waterflood performance in such reservoirs. In addition, they also introduced the coefficient of permeability variation, which can be statistically derived from a set of varied permeability values. This coefficient is commonly known as the Dykstra-Parsons' coefficient of permeability variation, V_{DP}. The coefficient of permeability variation is simply the ratio between the difference of P86 to P50 divided by P50 taken from a set of permeability values. Several other authors have also presented their methods of predicting waterflood performance in non-communicating stratified systems.[3,4,5]

It is in fact that most stratified reservoirs do exhibit some conditions in which crossflow is very likely to take place during the displacement process. Therefore the second type of methods for predicting waterflood performance that appeared in literature is for a reservoir in which crossflow between layers occurs. In this case, no impermeable barrier is present between layers, and consequently calculations have to account for crossflow that may occur during the displacement process. Goddin *et al.*[6] presented a paper discussing waterflood performance in a stratified system with crossflow. Their study made use of numerical simulation and was performed on a field-scale model of a two-layer, water-wet sandstone reservoir. They showed that the computed oil recovery for such system was always intermediate between that predicted for a uniform system and that for a stratified reservoir with no crossflow. However, their study did not account for cases in which the models are comprised of more than two layers as well as the effect of permeability ordering in vertical direction.

Crossflow is a vertical flow from one layer to another in a stratified reservoir. There are three contributing forces initiating crossflow namely, viscous force, gravity force, and capillary force.[7] Several authors have attempted to perform analysis on crossflow caused by each of these forces.[8,9] Gaucher and Lindley[10] presented a paper contained results from an experiment conducted on scaled reservoir models with a five-spot waterflood pattern. They used several models of two-layered reservoirs of uniform thickness to describe the effects of injection rate and permeability stratification on waterflood recovery efficiency involving the effects of the three types of crossflow (*i.e.* viscous, gravitational, and capillary). The results showed that the degree and distribution of permeability stratification was an extremely important factor to the oil recovery efficiency. It was also shown that for a two-layered reservoir model, the position of the more permeable layer had a greater effect on oil recovery than did the changes in injection rate.

Goddin *et al.*[6] also used several varied parameters to investigate their contributions on waterflood performance in such systems. Their results showed that capillary and viscous crossflows did have significant effects on waterflood performance. Maximum crossflow due to capillary and viscous forces was found to occur in the vicinity of the flood front in the more permeable layer. They found that, in the case of capillary crossflow, the initial capillary pressure in the reservoir and that prevailing in the water-invaded region behind the flood front was a very determining factor. Viscous crossflow is such as to equalize the horizontal pressure gradients in adjacent layers. The effect of gravity to crossflow was also investigated. In a two-layered system, when the more permeable layer was on the bottom, gravity forces caused the denser fluid (*i.e.* water) to drain into the more permeable layer with unfavorable effect on the oil displacement efficiency, and when the more permeable layer was on the top, water tended to flow from the loose (more permeable) into the tight (less permeable) layer, with favorable effect on the displacement efficiency. It was also mentioned that for mobility ratios less than unity, crossflow in such system was favorable.

Zapata and Lake[8] attempted to provide an analytical theory considering the contribution of viscous crossflow to fluid flow in a stratified reservoir. In their work, several simplifying assumptions were made. The effects of gravity and capillary forces on crossflow were neglected as well as viscous fingering and several other aspects. The only determining factor on which crossflow solely depend is the pressure gradient formed by the displacing and displaced fluids having unequal mobilities. The direction of viscous crossflow is governed by the mobility ratio of the interacting fluids (*i.e.* water and oil). For a favorable displacement ($M < 1$), the direction of crossflow is from the low to the high velocity layer at the leading front and in the reverse direction at the trailing front as indicated by **Fig. 1**. This results in receding and advancing of the leading and trailing fronts respectively, which consequently improve the vertical sweep efficiency of such displacement compared to that where no crossflow is encountered since the flood front becomes more sharpening (piston-like). For cases of reservoir models with three or more layers, it was indicated that, different permeability orderings of the layered models produced different vertical sweep efficiency for the corresponding water-oil displacements.

Methodology

Cases Studied. Several cases were created through conceptual reservoir modeling. The first step considered in creating such cases is to prepare four sets of varied permeability values ranging from 0.6 to 0.9 in terms of their Dykstra-Parsons coefficients of permeability variation, V_{DP}. This range of V_{DP} is chosen since most heterogeneous reservoirs exhibit such variation of permeability values. This preparation is accomplished by making use of a computer program to generate permeability values that falls within the expected range of variation expressed by their $V_{DP.}$ Therefore, each set contains as many as twenty-five values of permeability since each model consists of twenty-five layers. These values of permeability are an arbitrary function of porosity such that low values of permeability result from low values of porosity and vice versa.

These sets of permeability values were then assigned to the simulator with two different trends, namely decreasing upward and increasing upward. A decreasing upward permeability trend represents a fining upward grain size distribution (most permeable layer on bottom of the reservoir) and an increasing upward permeability ordering represents a coarsening upward grain size distribution (most permeable layer on top of the reservoir). Thus, we have eight sets of permeability data coming from two different grain size distributions in which each consists of four sets of permeability values.

Another set of permeability values is also considered here. This set of data consists of permeability values that exhibit very low variation (very small V_{DP}), which is used to represent the performance of a reservoir with no permeability stratification (uniform system). In this case, a set of permeability values with a coefficient of variation of 0.02 is prepared.

Several modified data sets are also prepared so that the output of the simulator can adequately present the effects of some varied variables that are expected to be seen from the calculation results. These modifications consist of two types as described as follows:

1. Variation on the values of vertical-to-horizontal permeability ratio, k_v/k_h, in order to see the effect of crossflow magnitude. A value of k_v/k_h being very small (close to zero) indicates a very minimum crossflow and is used in this simulation study to represent the case in which no vertical communication takes place between layers.
2. An alteration in several permeability values within the layers so that the model does not exhibit an absolute fining upward or coarsening upward grain size distribution, but is still considered to generally exhibit either one of the two. This is accomplished by generating a set of random numbers to be employed as multiplying factors so that the effect of realization, in which no absolute fining or coarsening upward of grain size distribution can be found in the field, can also be represented by the simulator results.

A generalization of the simulator results is obtained by normalizing the producing oil rate and time as to be able to describe the performance of different reservoir models in a general way. This is accomplished by analyzing the performance of the reservoirs in terms of oil recovery as fractions of the original oil in place and the amount of cumulative injected water as fractions of the total pore volume of the reservoir.

Simulator Used. In the present study, the use of a three-dimensional streamline simulator is fully encouraged. All the models built for this study have been set in such a manner as to be able to describe the effect of spatial placement of vertical heterogeneity on waterflood performance in the simplest way.

The simulator first solve the pressure solutions for a certain time-step by applying an IMPES (Implicit Pressure Explicit Saturation)-like method and proceed with solving for the saturation by using a front-tracking method. This front-tracking method does not depend on grid size and model geometry since it tracks the saturation fronts (discontinuities in saturation) along the streamlines/tubes established from the pressure solution, which results in a typical Bukley-Leverett[11] saturation profile. This is somehow a quite distinguishing technique compared to the methods commonly used by other reservoir simulators.

Streamtube models was first proposed by Muskat and advanced by several other authors.[7] Streamtubes for the reservoir model are drawn from a set of estimated pressure values where it is assumed that there is no crossflow between the tubes. The purpose of this method was originally to reduce a set of two-dimensional displacement problems to a set of one-dimensional problems. In this simulator, the streamtubes are drawn from isobar lines (obtained from the implicitly solved pressure equations) and then the saturation equations are solved along the streamlines resulting in the reduction of a set of three-dimensional saturation equations to a set of one-dimensional saturation equations.

Model Building

Pertinent reservoir and fluid data are presented in Table 1 while relative permeability data is shown in the following Table 2. From these relative permeability values, the end-point mobility ratio, M, was calculated as follows:

$$M = \frac{\lambda_w}{\lambda_o} = \frac{\left(\dfrac{k_{rw}}{\mu_w}\right)_{@S_{or}}}{\left(\dfrac{k_{ro}}{\mu_o}\right)_{@S_{wi}}} = \frac{\dfrac{0.318}{0.96}}{\dfrac{0.97}{0.95}} = 0.3224 \quad \ldots\ldots\ldots \quad (1)$$

Table 2–Relative Permeability Data

S_w	k_{rw}	k_{ro}
0.2	0	0.97
0.25	0.003	0.94
0.35	0.028	0.83
0.4	0.069	0.171
0.55	0.143	0.05
0.7	0.318	0
1	0.318	0

The permeability and porosity values for the reservoir layers are shown in Tables 3 through 6. All the permeability values are set in a decreasing upward manner (fining upward grain size sequence). Four other sets of permeability data have exactly the same values (with the same V_{DP}) as those shown in Table 3 through 6 but are set in an increasing upward manner (coarsening upward grain size sequence).

For our simulation study, only the effects of the two types of grain size distribution are considered (*i.e.* fining upward and coarsening upward), no mixed of grain size distribution is considered. We assumed that there will be no cases in which the grain size distribution of a particular reservoir would follow the combination of the two (fining and coarsening or vice versa) since there should be a fine permeability barrier between the two types of grain size sequence due to different geological time in which the sedimentation of such reservoir takes place.[1]

However, reservoirs do exhibit certain conditions in which grain size is not distributed in an absolutely fining or coarsening upward manner. Therefore, in order to encounter the effect of such phenomena, several models containing non-absolute fining upward or coarsening upward grain size sequence are also investigated. The non-absolute condition is attained through generating several other models of which the permeability values of some of the layers are allowed to exhibit non-absolute trend. Thus the results obtained from the simulation should be able to describe the general effects of permeability trend on waterflood performance in such reservoirs.

In this study, it is assumed that the level of water-oil contact is so far below the reservoir that the distribution of water saturation is uniform throughout the reservoir (before displacement takes place) and thus the values are equal to the minimum water saturation (*i.e.* irreducible water saturation). Consequently, there is no need to define capillary pressure-water saturation relationship for the model.

Results And Observation

Results. Figs. 2 through **5** shows the effects of permeability trend on waterflood performance of the stratified models in terms of oil recovery versus cumulative injected water. **Figs. 6** and **7** show the effects of different level of permeability variation, which is represented by varied values of V_{DP} on waterflood performance in stratified reservoir in terms of oil recovery versus cumulative injected water. The effects of crossflow magnitude may be implied by varying the values of vertical-to-horizontal permeability ratio, k_v/k_h. These effects are indicated by **Figs. 8** and **9**. As mentioned, it is quite impossible for a certain formation to have neither an absolutely fining upward nor coarsening upward grain size sequence. Normally, there will be some layers that exhibit less fine or less coarse grain size contrary to their distribution, but still can be generally considered as to have a fining upward grain size sequence or coarsening upward grain size sequence. In this study, the term *noise* is used to indicate such phenomenon. Therefore verification of the results is done by allowing the models to have certain layers in which the permeability values does not solely exhibit a decreasing upward or increasing upward trend. A computer program is used to generate a certain range of random numbers that are assigned to the models as multiplying factors of the permeability values. A check should be made on their coefficient of variation to avoid the models from having different levels of permeability variation. In this specific case, verification is performed on systems with V_{DP} = 0.8. As many as five additional models were run, in which each model represents the effect of realization due to actual field condition. **Figs. 10** through **14** shows the effects of realization in which each figure represents different type of noise. From these charts, it is clear that realization does not change the trend of the performance of such stratified reservoirs due to permeability trend (grain size distribution). The waterflood performance of a reservoir consisting of layers with increasing upward permeability still lies above that of a reservoir with decreasing upward permeability. Thus, all the results are valid and consequently should be able to represent the actual performance of such reservoirs.

Regression Analysis. It was promptly observed from the above results that the waterflood performance of the two distributions is different from one to another. Therefore, the next step taken in this study is to perform regression analysis on the simulator results to relate such specific distributions to oil recovery. In other words, this analysis relates oil recovery (dependent variable) to three independent variables namely, cumulative injected water, coefficient of permeability variation, and another independent variable called the median of "horizontal permeability ratio of sequential layers." A correlation is presented as the product of data analysis. This correlation succeeds in distinguishing the performance of a reservoir with increasing upward permeability trend and that of a reservoir with decreasing upward permeability trend.

The term horizontal permeability ratio of sequential layers refers to a value that can be obtained by following the procedure as taken in the following example:

a. Consider a reservoir consisting of layers of five varied horizontal permeability values. The permeability values are 15, 20, 100, 125, and 500 mD, respectively. These layers are ordered in two different manners *i.e.* decreasing upward (least permeable layer on top) and increasing upward (most permeable layer on top).
b. For those values ordered in a decreasing upward manner, the values of "horizontal permeability ratio of sequential layers" are 0.75, 0.2, 0.8, and 0.25, respectively. So, each value is expressed as their fraction relative to the next layer in the sequence. The last value (500 mD) does not have any ratio since there is no other layer beneath the layer.
c. For those values ordered in an increasing upward manner, the values of "horizontal permeability ratio of sequential layers" are 4, 1.25, 5, and 1.33, respectively. In this case, the last value (15 mD) has no ratio since there is no other layer beneath the layer.
d. Therefore the median (50 percentile) for those values of a decreasing upward system is 0.5 and for those of an increasing upward system is 2.665.

A convention that has to be made here is that the calculation starts from the uppermost layer towards the lowermost layer.

The analysis was performed on 160-observation data. The comparison between the simulator results and correlation results can be seen in **Fig. 15**. This comparison is based on a stratified system with V_{DP} equals 0.75 and the only difference is in the type of permeability trend. This can also be accounted as a validation to the correlation since the simulator results of this system (V_{DP} = 0.75) were not used as the observation data for deriving the correlation.

Another validation is performed by using actual field data. In this case, predictions are made on oil production rates resulting from a certain amount of injected water taken from simulated field injection rates data. These predicted values are then compared with those obtained from field oil production rates data. The result, as can be seen in **Fig. 16**, shows very good agreement between each other.

Discussion

From **Figs. 2** to **5**, we can see the effects of different permeability trends on waterflood performance provided that all other properties of the models are similar. It is very clear that, for a certain stratified reservoir, an increasing upward permeability trend should result in a better waterflood performance of the reservoir compared to that of a decreasing upward permeability trend. The computed amount of oil that can be recovered (oil recovery) from a waterflooded reservoir with increasing upward permeability trend is larger than that with an opposite trend of permeability. The two different trends of permeability variation cause crossflow to yield different effects on displacement process within the reservoir. For a reservoir with increasing upward permeability trend, the effects of crossflow are more favorable compared to that for a reservoir with the opposite permeability trend. In addition, as Goddin *et al.*[6] noted earlier, the oil recovery for systems with crossflow (both with increasing and decreasing upward permeability trends) are always intermediate between that predicted for a uniform system and that for a stratified reservoir with no crossflow.

As stated in the previous section, maximum crossflow due to viscous forces occurs at the vicinity of the front in the more permeable layer. However, according to Zapata and Lake, viscous crossflow does not only take place at the leading front in the more permeable layer, but also at the trailing front in the less permeable layer.[8] For a displacement with mobility ratio of the interacting fluids being less than unity ($M < 1$), the direction of viscous crossflow is from the less to the more permeable layer at the leading front and from the more to the less permeable layer at the trailing front as illustrated by **Fig. 1**. In our case, mobility ratio is less than unity and water is displacing oil, therefore oil flows from the less to the more permeable layer at the leading front and water flows counter-currently at the trailing front from the more to the less permeable layer. Since the number of layer is more than two, a relatively similar mechanism is considered to occur repeatedly in the adjacent layers throughout the reservoir. These should result in receding and advancing of the fronts within the more and the less permeable layers resulting in a better performance of a stratified reservoir with crossflow compared to those with no-crossflow. In other words, the existence of crossflow enhances the vertical sweep efficiency of the displacement in stratified reservoirs.

When the more permeable layers are on the upper part of the reservoir, crossflow due to gravity forces favors the flow of water to drain toward the less permeable layers on the lower part of the reservoir. Thus, vertical sweep efficiency is even better than that when only viscous crossflow occurs due to the favorable effect of gravity forces. On the other hand, when the more permeable layers are on the lower part of the reservoir; since viscous crossflow still moves toward the same direction (oil flows from the less to the more permeable layers at the leading front and water flows counter-currently at the trailing front) and gravity forces still forces water to drain into the lower part of the reservoir, the effect of gravity crossflow is no longer favorable. This phenomenon had also been observed by Berruin and Morse[12] when conducting their investigation. However, they mentioned that there had been certain limits to which this condition still holds due to injection rate. In our study, the effect of injection rate is already encountered by normalizing the cumulative injected water by dividing it to the reservoir pore volume. **Fig. 17** illustrates this phenomenon in a stratified system with three layers where in our case the relatively similar mechanism is assumed to occur repeatedly. The black arrows pointing towards the lower part of the reservoir indicate the contribution of gravity forces to crossflow while the other bended arrows indicate the direction of viscous crossflow in adjacent layers.

It should be noted here that one way to better understand and extend such mechanism to a more complex case is through water saturation profiles at different time stages during the displacement process. It was found in our study that in systems with no-crossflow, after water has broken through within the most permeable layer, most of the injected water will continue flowing toward that layer (most permeable), leaving other layers remain poorly swept. On the other hand, in systems with crossflow, the movement of fluid (*i.e.* oil and water) in vertical direction enhances vertical sweep efficiency, with different contribution depending upon permeability trend.

As can also be seen in **Figs. 2** to **5**, the difference in performance between reservoirs with increasing upward permeability trend and that with an opposite permeability trend will reduce as the reservoir achieves homogeneity. For models with V_{DP} being equal to 0.6, the difference in performance due to different trend of permeability variation is less than those of which the Dykstra-Parsons' coefficients are equal to 0.7, 0.8, and 0.9. Therefore the level of heterogeneity has significant impact on the difference in performance due to different trends of permeability variation. As the reservoir achieves homogeneity, the effect of permeability trend becomes less significant on waterflood performance. This phenomenon can be recognized more clearly through the next **Figs. 6** and **7**. It is shown that in both cases, *i.e.* systems with increasing upward and decreasing upward permeability trend; as the level of heterogeneity decrease (decreasing V_{DP}), oil recovery from such reservoirs will increase. This is due to the tendency of the reservoir to act more like a uniform system as discussed in the preceding section.

Now we will consider the effect of crossflow magnitude. From **Figs. 8** and **9**, we can see that a relatively small change in k_v/k_h does not have any significant effect on the models performance. However a change up to one hundred folds may have significant impact on the performance as indicated by the lines representing the performance of such reservoirs with k_v/k_h being 0.001. It is shown that a change of k_v/k_h from 0.1 to 0.001 has greater impact on the performance of a reservoir with increasing upward permeability trend. When compared to the performance in which k_v/k_h equals 0.1; for a system with decreasing upward permeability trend, a change of k_v/k_h to 0.001 may decrease the oil recovery up to around 2% whereas for a system with increasing upward permeability trend the same change in k_v/k_h may decrease the oil recovery up to more than 10%. In general, a decrease in crossflow magnitude would result in worse vertical sweep efficiency. However, in most actual reservoirs the value of k_v/k_h usually falls not very far from 0.1.

As mentioned before, it is very likely to find a reservoir in which the permeability does not exhibit an absolutely decreasing or increasing upward trend. There may be several layers among all the layers constructing the reservoir that do not necessarily exhibit an absolute trend, but still considered to generally follow either one of the two trends. For such cases, as shown in **Figs. 10** to **14**, the difference in performance due to different permeability trends does not follow the phenomena shown by **Figs. 2** to **9** (decrease with decreasing level of heterogeneity) due to the existence of noise. This is also the reason why some of the models do not exhibit increasing oil recovery although their heterogeneity levels have been reduced. However, it is shown that a reservoir with increasing upward permeability trend still yields better performance compared to that with the opposite permeability trend provided that all other properties are similar.

The last part considered in this study is performing some data analysis of the results. From all the results, we can see that even though the only difference between a reservoir and another is only in permeability trend, performance of either of the model may vary from one to another. The level of heterogeneity (indicated by Dykstra-Parsons' coefficient of permeability variation) is not the only factor influencing waterflood performance in stratified reservoirs. We also have to account for the impact of permeability trend. Of course, the amount of injected water is also important; as more and more water is injected into the layers comprising the reservoir, more and more oil can be recovered. In other words, as time increases, more and more oil will be swept out of the stratified reservoir resulting in higher cumulative oil recovery.

A question is what other parameter that may be able to affect the performance of such stratified reservoir as to distinguish the effect of permeability trend on waterflood performance. In this study, we try to relate oil recovery not only to the amount of injected water and coefficient of permeability variation but also to another parameter called "median of the horizontal permeability ratio of sequential layers," MPR.

It is shown that, for a stratified reservoir with increasing upward permeability trend, the median value of the horizontal permeability ratio of sequential layers will be more than unity whereas for that with decreasing upward permeability trend, the median value will be less than unity. Hence now there is a fine line separating the system of increasing upward permeability trend from that of decreasing upward permeability trend. Furthermore, the use of this parameter should be helpful in order to distinguish stratified systems with increasing upward permeability trend (coarsening upward grain size distribution) from stratified systems with decreasing upward permeability trend (fining upward grain size distribution).

A collection of simulator results was observed, and regression analysis was performed on 160 sets of data in order to derive a correlation relating oil recovery to MPR, pore volume of injected water, and coefficient of permeability variation. As a result, we can rely on this correlation to approach the simulator results to distinguish the effect of permeability trends on waterflood performance in stratified reservoir. The correlation is given as follows:

$$\begin{aligned}\text{Oil recovery} = {} & 0.089406(\text{MPR}) - 0.1485(V_{DP}) \\ & - 12.2323((0.1 \times \text{PVI})^{-0.0069}) + 12.80076 \qquad \ldots\ldots\ldots \ (2)\end{aligned}$$

where MPR = median of horizontal permeability ratio of sequential layers and PVI = cumulative injected water as fraction of reservoir pore volume.

A validation to the correlation is performed by using it to predict waterflood performance of such system with V_{DP} of 0.75, one case that has not been used in the observation samples. The correlation results show good agreement with simulator results, as can be seen in **Fig. 15**.

From **Fig. 16**, it can also be seen that, the correlation can be used to predict oil production rate with relatively good accuracy for a certain rate of injected water. The actual oil production rate data were taken from Bangko Field, in Duri, Riau, Indonesia for a system with one producer and one injector. At early phase of the production period, the predicted oil rates show higher values than those of the actual data due to the assumption of allowing waterflood to start as the reservoir model is put on production. It is also observed that, at the early stage of production, oil rates resulting from a system with increasing upward permeability trend, are higher than those from a decreasing upward permeability trend. This will consequently result in higher recovery for a system with increasing upward permeability trend as compared to that with the opposite permeability trend.

Concluding Remarks

From our results, keeping in mind the limitations and assumptions applied to this study, we can derive the following conclusions:

1. The waterflood performance in stratified reservoirs depends upon the classification of grain size distribution along the vertical direction. A stratified reservoir with increasing upward permeability trend will yield better waterflood performance (higher vertical sweep efficiency) as compared to that of the opposite permeability trend "provided that all other properties are similar."
2. In a stratified reservoir the waterflooding oil recovery decreases as the permeability variation in vertical direction increases. This decrease will be greater in a reservoir with decreasing upward permeability trends. However, for systems exhibiting either absolute increase or decrease in upward permeability trends, as reservoirs achieve uniformity; the difference in performance "due to permeability trend" will reduce.
3. The presence of crossflow will generally improve vertical sweep efficiency of waterflood in stratified reservoirs. This phenomenon is more notable in a reservoir with increasing

upward permeability trend. Moreover, for reservoirs with either increasing or decreasing upward permeability trends, if crossflow occurs, the waterflood performance will be intermediate "between that of a uniform system and that of a stratified system with no-crossflow."

4. In stratified reservoirs with different grain size distribution, the median value of horizontal-permeability-ratio of sequential layers (MPR) is an alternative parameter to distinguish waterflood performance.

Considering the above conclusions, several new concerns come to light and therefore we are suggesting further studies in order to discover ways to:

1. Improve vertical sweep efficiency in reservoirs with decreasing upward permeability trend (fining upward grain size distribution).
2. Evaluate the effects of different thicknesses "of the layers comprising the reservoir" on waterflood performance.

Nomenclature

k = permeability, mD
k_r = relative permeability
k_h = horizontal permeability, mD
k_v = vertical permeability, mD
k_{ro} = relative permeability to oil
k_{rw} = relative permeability to water
M = mobility ratio
S_{or} = residual oil saturation, fraction
S_{wi} = initial water saturation, fraction
V_{DP} = Dykstra-Parsons' coefficient of variation
μ_o = oil viscosity, cp
μ_w = water viscosity, cp
ϕ = porosity, fraction
λ_o = oil mobility
λ_w = water mobility

Superscript:

^{o} = end-point

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Table 1–Reservoir and Fluid Data

Reservoir length	= 500 ft divided into 10 blocks of equal length (50 ft each)
Reservoir width	= 500 ft divided into 10 blocks of equal length (50 ft each)
Total thickness of reservoir	= 50 ft
Number of layers	= 25
Thickness of each layer	= 2 ft
Depth to top of reservoir	= 1000 ft
V_{DP} range	= 0.6 – 0.9
Injection rate	= 250 STB/day
Oil Formation Volume Factor	= 1.100 RB/STB
Oil Density	= 54.31 lb/ft^3
Oil Viscosity	= 0.95 cp
Water Formation Volume Factor	= 1.0034 RB/STB
Water Density	= 62.998 lb/ft^3
Water Viscosity	= 0.96 cp
Number of wells	= 2; one injector and one producer

Table 3–Permeability & Porosity Values with V_{DP} = 0.6 in Descending Order

Layer	k, mD	ϕ, fraction
1	0.72	0.008
2	2.02	0.03
3	4.01	0.06
4	6.88	0.08
5	10.84	0.09
6	16.20	0.11
7	23.36	0.12
8	32.86	0.13
9	45.38	0.15
10	61.83	0.16
11	83.48	0.17
12	112.07	0.18
13	150.00	0.19
14	200.92	0.20
15	269.85	0.21
16	364.46	0.22
17	496.64	0.23
18	685.56	0.24
19	963.58	0.26
20	1389.96	0.27
21	2080.51	0.28
22	3284.55	0.30
23	5640.43	0.32
24	11261.37	0.35
25	32038.90	0.38

Table 4–Permeability & Porosity Values with V_{DP} = 0.7 in Descending Order

Layer	k, mD	ϕ, fraction
1	0.29	0.009
2	0.98	0.01
3	2.20	0.04
4	4.12	0.06
5	7.00	0.08
6	11.18	0.10
7	17.14	0.11
8	25.52	0.13
9	37.18	0.14
10	53.35	0.15
11	75.73	0.16
12	106.76	0.18
13	150.00	0.19
14	210.97	0.20
15	297.63	0.21
16	422.64	0.23
17	606.42	0.24
18	883.28	0.25
19	1313.86	0.27
20	2014.57	0.28
21	3225.56	0.30
22	5495.83	0.32
23	10330.18	0.34
24	23153.25	0.37
25	78518.16	0.42

Table 5–Permeability & Porosity Values with V_{DP} = 0.8 in Descending Order

Layer	k, mD	ϕ, fraction
1	0.12	0.007
2	0.48	0.009
3	1.20	0.01
4	2.46	0.04
5	4.52	0.06
6	7.72	0.08
7	12.57	0.10
8	19.82	0.12
9	30.47	0.13
10	46.03	0.15
11	68.69	0.16
12	101.71	0.18
13	150.00	0.19
14	221.52	0.20
15	328.29	0.22
16	490.14	0.23
17	740.49	0.25
18	1138.06	0.26
19	1791.50	0.28
20	2919.90	0.30
21	5001.03	0.32
22	9196.66	0.34
23	18922.21	0.36
24	47616.10	0.40
25	192565.58	0.45

Table 6–Permeability & Porosity Values with V_{DP} = 0.9 in Descending Order

Layer	k, mD	ϕ, fraction
1	0.05	0.007
2	0.23	0.009
3	0.66	0.01
4	1.47	0.02
5	2.92	0.05
6	5.32	0.07
7	9.22	0.09
8	15.39	0.11
9	24.97	0.12
10	39.72	0.14
11	62.31	0.16
12	96.89	0.17
13	150.00	0.19
14	232.60	0.21
15	362.11	0.22
16	568.43	0.24
17	904.24	0.25
18	1466.39	0.27
19	2442.83	0.29
20	4232.16	0.31
21	7754.26	0.33
22	15391.23	0.36
23	34666.61	0.39
24	97955.21	0.42
25	472635.80	0.48

Table 7–Permeability values with noise

No.	Noise_1	Noise_2	Noise_3	Noise_4	Noise_5
1	0.11	0.12	0.10	0.13	0.10
2	0.47	0.46	0.50	0.45	0.49
3	1.18	1.20	1.19	1.22	1.19
4	2.33	2.67	2.29	2.64	2.32
5	4.06	4.10	4.01	5.01	5.15
6	9.32	8.46	7.59	6.41	8.98
7	11.49	15.47	10.65	14.23	14.55
8	17.00	16.32	25.13	23.52	17.06
9	34.13	27.54	29.59	33.78	37.94
10	31.51	55.06	54.16	66.15	60.26
11	58.36	51.34	72.67	104.66	52.50
12	163.13	69.26	132.97	98.64	68.76
13	96.52	101.60	100.23	168.99	224.01
14	147.99	372.36	253.53	375.17	177.46
15	239.54	368.16	268.46	391.03	565.66
16	886.14	530.49	827.45	902.73	332.85
17	1074.30	733.74	1036.31	955.58	1014.80
18	939.60	1974.45	1074.00	1305.15	1022.84
19	1214.02	1341.44	1092.56	2802.85	1197.53
20	2047.55	1916.31	5137.69	1818.01	5106.97
21	5036.97	5580.45	6207.28	5214.82	4223.04
22	4279.05	22866.76	22558.14	14231.46	22713.42
23	24343.54	11647.50	11039.24	33797.79	23396.36
24	35808.70	102088.32	62561.57	28821.71	21446.30
25	188663.14	84578.96	330776.33	61267.35	58894.97

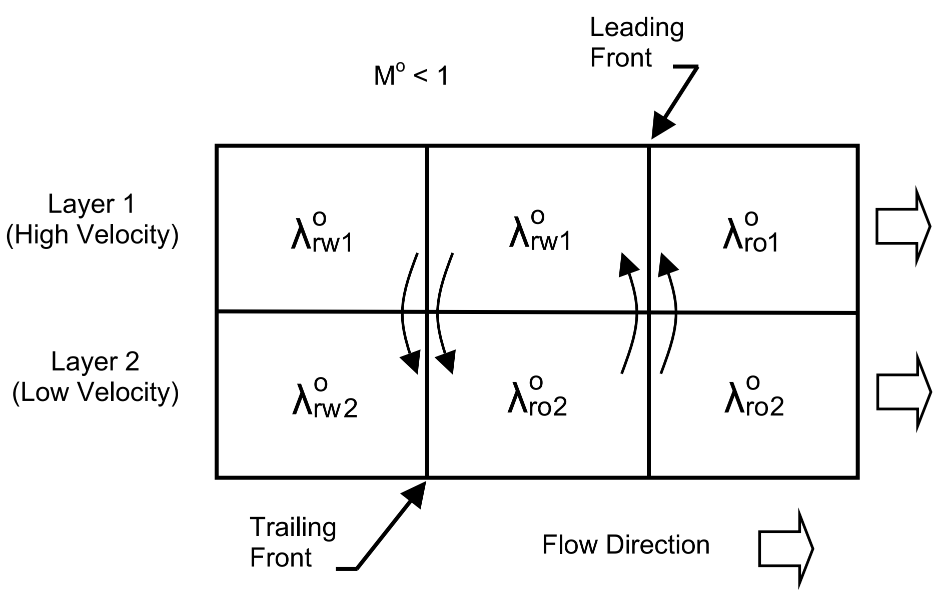

Fig. 1–Direction of viscous crossflow for a two-layer model with end-point mobility ratio of less than unity (M<1).[8]

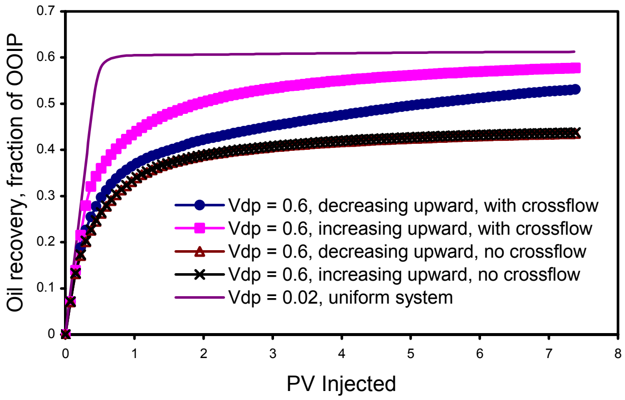

Fig. 2–Effects of Permeability Trend with V_{DP} = 0.6 as Compared to Systems of Uniform Permeability and No Crossflow.

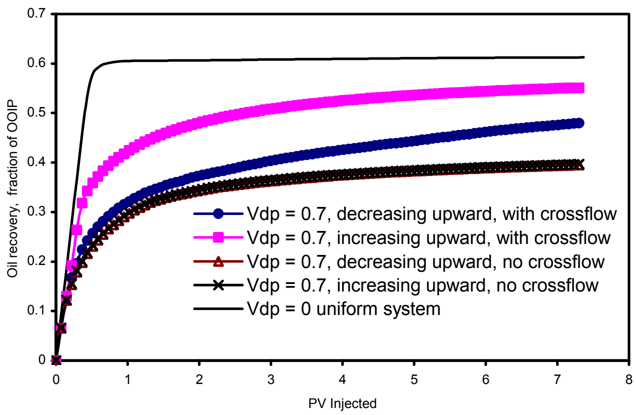

Fig. 3– Effects of Permeability Trend with V_{DP} = 0.7 as Compared to Systems of Uniform Permeability and No Crossflow.

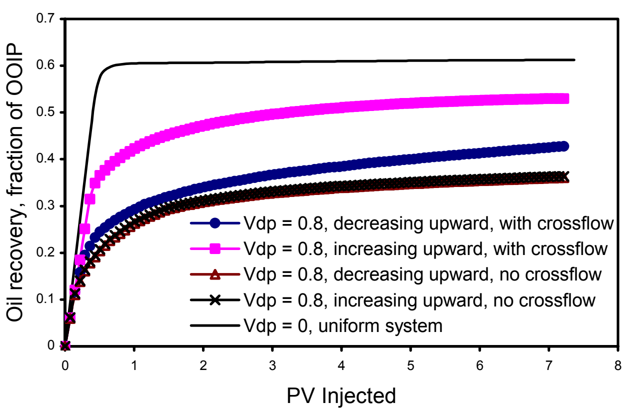

Fig. 4–Effects of Permeability Trend with V_{DP} = 0.8 as Compared to Systems of Uniform Permeability and No Crossflow.

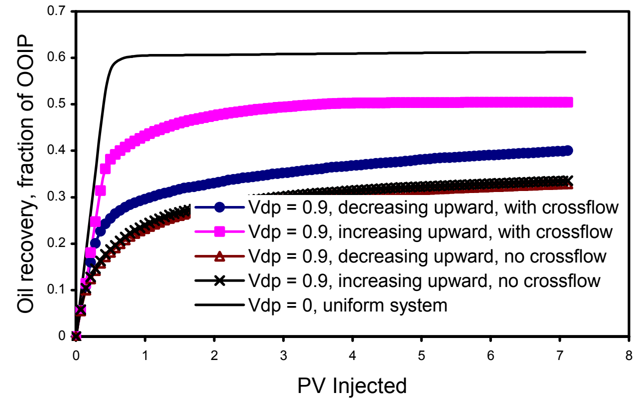

Fig. 5–Effects of Permeability Trend with V_{DP} = 0.9 as Compared to Systems of Uniform Permeability and No Crossflow.

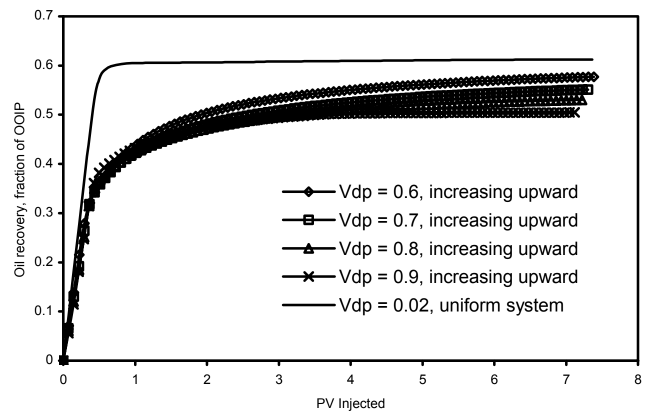

Fig. 6–Effects of Varied V_{DP} with Increasing Upward Permeability Trend as Compared to a System of Uniform Permeability.

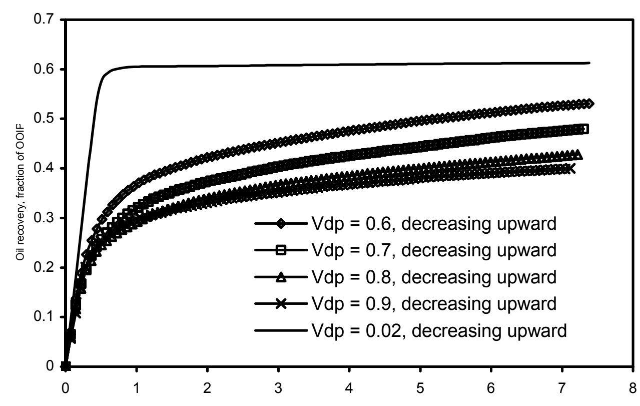

Fig. 7–Effects of Varied V_{DP} with Decreasing Upward Permeability Trend as Compared to a System of Uniform Permeability.

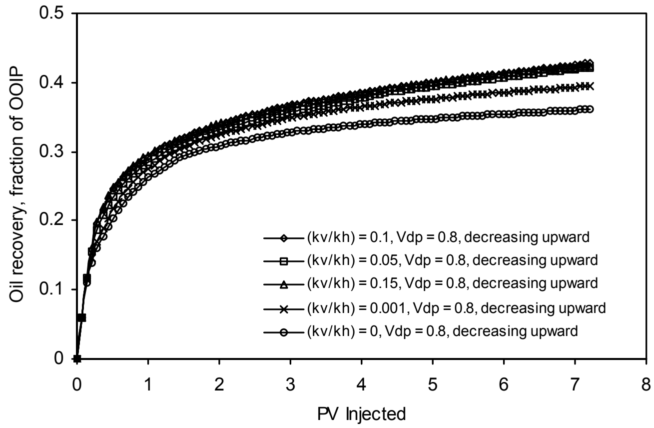

Fig. 8–Effects of Crossflow Magnitude with Decreasing Upward Permeability Trend.

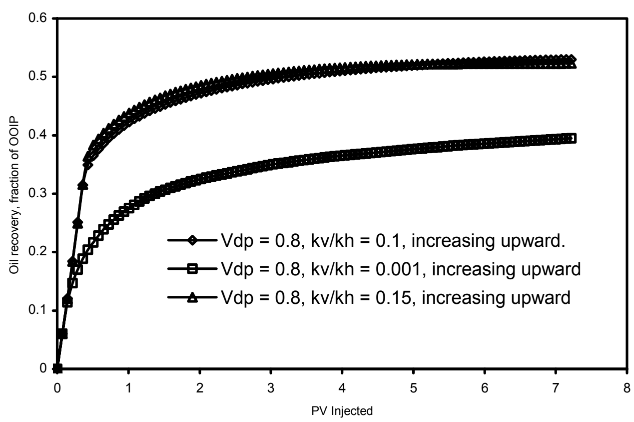

Fig. 9–Effects of Crossflow Magnitude with Increasing Upward Permeability Trend.

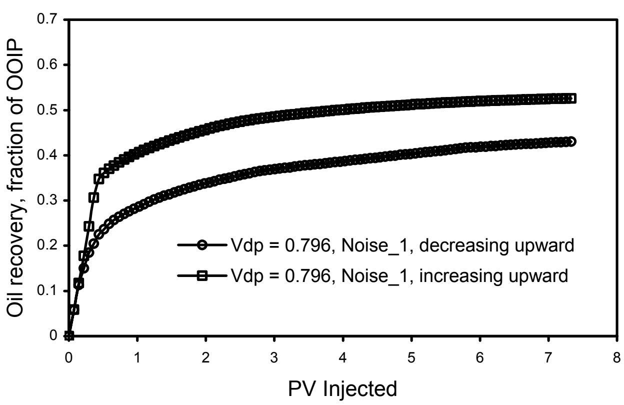

Fig. 10–Effect of Realization, 1st Noise.

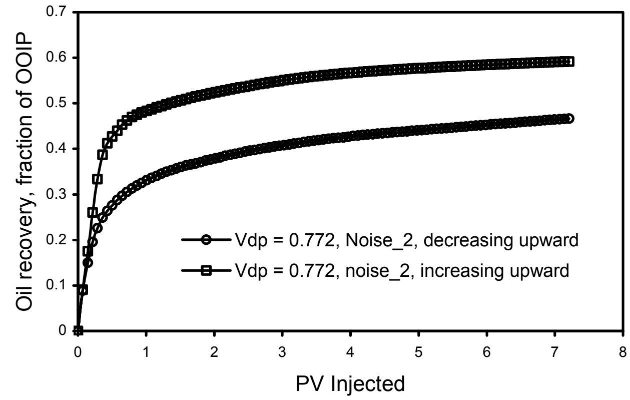

Fig. 11–Effect of Realization, 2nd Noise.

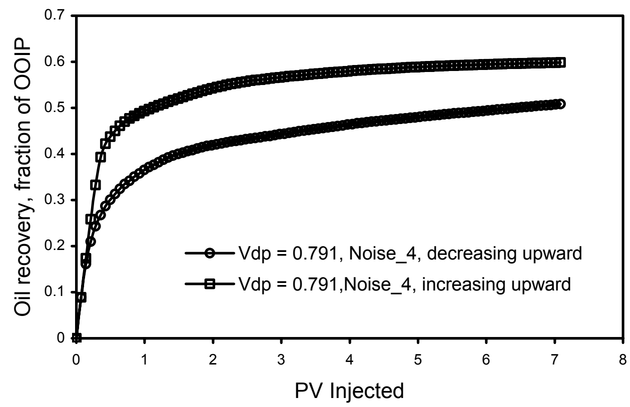

Fig. 13–Effect of Realization, 4th Noise.

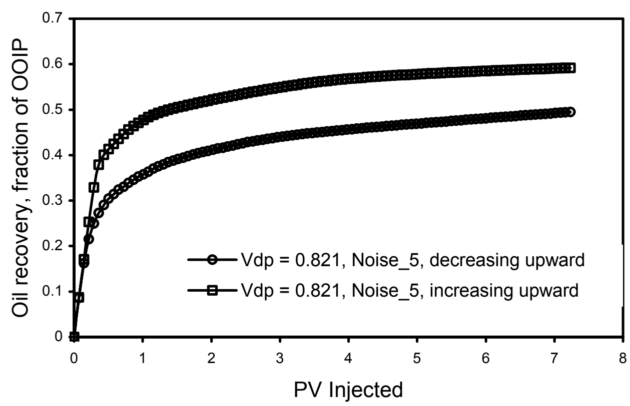

Fig. 14–Effect of Realization, 5th Noise.

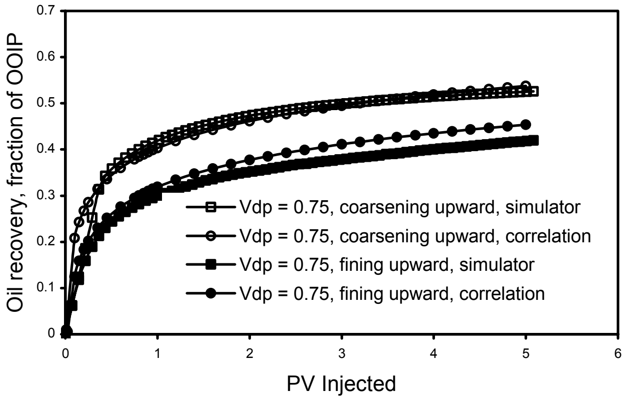

Fig. 15–Comparison Between Simulator Results and Correlation Results.

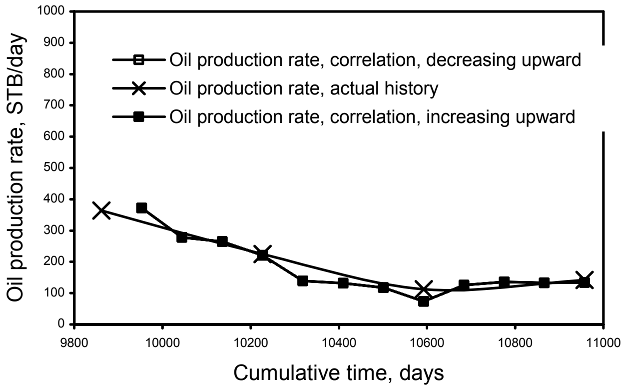

Fig. 16–Comparison Between Correlation Results and Historical Production Data.

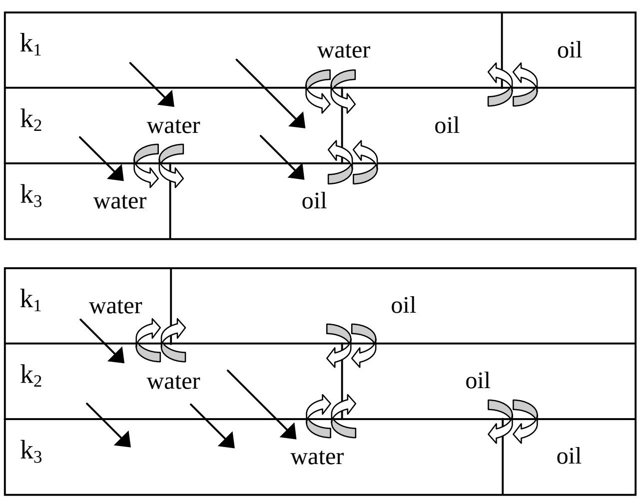

Fig. 17–Crossflow in increasing upward ($k_1>k_2>k_3$, top) and decreasing upward ($k_1<k_2<k_3$, bottom) permeability trend formations.